3/1/84
C8650-4A

09325 1957257 # 2 2021
JOSEPH MCNALLY
CONGRESSIONAL INFO SERVIC D
4520 EAST WEST HWY STE 800
BETHESDA MD 20814

Volume 62, Number 3
March 1984

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

LP&L, Waterford-3 get passing marks in audits

BATON ROUGE, LA—Two independent consultant studies addressing Louisiana Power & Light Company's management capabilities and construction cost efficiencies for the company's nearly-completed Waterford-3 nuclear plant contain conclusions generally favorable to this southeastern utility.

Both studies were ordered by the Louisiana Public Service Commission following a rate increase request filed by LP&L early last year.

Arthur Young & Company conducted a management audit of LP&L and Decision Management Company, Inc., investigated the cost increases of Waterford-3.

The Arthur Young study found that LP&L, assisted by its Systems Fuels division, has been able to purchase low-cost fuel oil and natural gas. The consultants also concluded that the company had extracted from its workforce an acceptable level of productivity and, in general, operating costs were monitored and controlled in an efficient manner.

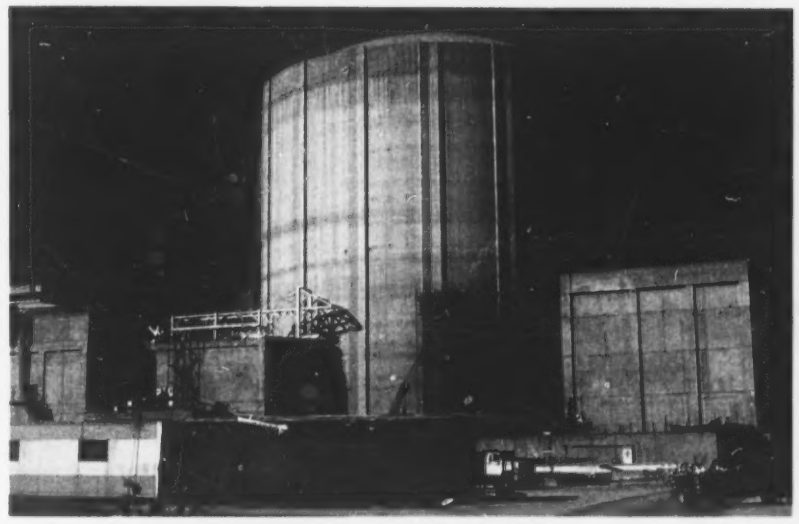
LP&L received passing marks for the manner in which it secured contracts and the Young investigators said they were convinced that the company had very capable people in its load forecasting and system planning areas. Recruitment policies and management salary levels were also approved by the consultants.

Waterford expenditures prudent

The Waterford-3 economic study concluded that while the total estimated cost of the plant ($2.65 billion), could not be termed "reasonable" in absolute terms, it was below the average cost of other nuclear plants built during the same period.

"The cost was primarily due to circumstances beyond LP&L's control, reflecting the difficulties of constructing these plants during the 1970s and early 1980s," Decision

Continued on page 13



The Waterford-3 plant costs less than other nuclear plants of the same generation, a consultant's study reports. Another study ok'd LP&L management practices.

Zimmer nuclear plant killed; coal unit eyed

Dan Utroska
Associate Editor

One of the most contentious and industry-crushing chapters in the history of the American nuclear power plant construction program has finally ended: the Zimmer nuclear plant has been terminated.

The announcement on January 21 by Cincinnati Gas & Electric, Dayton Power & Light, and Columbus and Southern Ohio Electric that they would discontinue all efforts to license the 810 MW plant marks the first time in U.S. nuclear power experience that a unit has been virtually completely built and then a decision made not to license the plant.

"We will be filing with the Atomic Safety and Licensing Board, in the near future, the appropriate legal papers for withdrawal of the application" for an operating license for Zimmer as a nuclear station, William H. Dickhoner, CG&E president and chief executive officer wrote to administrators at the Nuclear Regulatory Commission's Region III office in Illinois.

At the time of cancellation, the participants had invested $1.6 billion in the plant and it had been estimated that at least another $1.5 billion would have been necessary to complete the plant in accordance with NRC license requirements.

Zimmer, originally expected to be operational in 1975 for a cost of $240 million, has been plagued by charges of serious construction and quality assurance deficiencies. In November, 1982 the NRC stopped all safety-related work, pending an independent review of the licensee's management capabilities. Although the participants were able to get approval for one of their proposals for removing the NRC construction prohibition, two other plans—one to verify the quality of construction and another dealing with continuing construction—were under agency review when the utilities decided to end efforts to license Zimmer as a nuclear plant.

Conversion to coal?

In its announcement that it was ending any further construction expenditures on Zimmer as a nuclear facility, the participants said they had reached agreement to convert the power station to a coal-fired unit. However, short of the general statement that preliminary studies conducted by each of the participants indicated conversion to coal would be technically feasible and cost effective, no specifics on the conversion were available.

Asked what fraction of the current $1.6 billion investment in the nuclear unit would be applicable to the coal plant, CG&E spokesman Steven Brash said, "At this point we don't have a specific number on that."

Asked if it had been determined which nuclear components might be usable in a coal plant, Brash answered, "Not in specific detail." He mentioned, however, that the cooling tower, certain switchgear, auxiliary diesel generators, and some control elements could be used.

Brash said that an architect-engineering firm will be retained to determine the specifics of the economics and technical aspects of the conversion.

A week after its initial announcement, the three participant companies issued a press release declaring in part, "A great number of questions have been asked about the companies' plans. While we appreciate the interest in obtaining answers to these questions, a preliminary release of further information at this time would not serve any useful purpose. At some point in the near future when these engineering studies and cost evaluations have become more definitive, we will make appropriate information available."

Under the agreement-in-principle reached among the parties in the coal conversion plan, CG&E will purchase a larger share of the project from the other participants and will assume a correspondingly greater share of the associated costs. CG&E's ownership will be increased from 40 percent (its share of the Zimmer nuclear project) to 46.5 percent.

Dayton Power & Light's share will decrease from 31.5 to 28.1 percent.

Continued on page 11

More research needed

Reagan unveils acid rain plan

Don Minner
Assistant Editor

WASHINGTON, D.C.—After listening to both sides of the acid rain debate from his top advisors, President Reagan has decided that more research needs to be done before potential costly emissions control programs are mandated.

In his State of the Union Address in January, the President said he was going to increase the Environmental Protection Agency's (EPA) research budget from $28.8 million in fiscal 1984 to $55.5 million in 1985. The decision was somewhat of a surprise because EPA Administrator William Ruckelshaus had lobbied hard for a limited emissions control program involving 10 states.

When Ruckelshaus was sworn in last May, Reagan told him that acid rain should be his "top priority."

Throughout last year, pressure mounted on the administration to do something about acid rain. A number of scientific groups published studies suggesting a link between acid rain and sulfur dioxide from power plants. Also, the Canadian government and many U.S. politicians called for immediate emissions control programs. Fifteen bills were introduced in Congress calling for controls.

The National Acid Precipitation Assessment Program, a federal task force of scientists studying acid rain, said last summer that the major contributor to acid rain deposition in North America is probably man-made pollution. However, the scientists also cautioned that no exact link can be made between specific emissions and acid rain patterns.

Research pace quickens

Gary Foley, the EPA's top scientist in the group, told *EL&P* (Jan. 1984, p. 8) that the pace of the government's research program is increasing. He said that within five years, scientists will be able to specify what emissions need to be reduced to control acid rain.

Continued on page 2

Foreign Power Briefs

• **France, Britain, West Germany, Italy, and Belgium** have signed an agreement to share fast-breeder reactor technology, reports the *Wall Street Journal*. The Netherlands is expected to join the agreement later in the year. Officials of Great Britain say the group has no current plans for joint construction of a fast-breeder reactor, however.

• **The Japanese government** has decided to allow nuclear power equipment to be sold to China, with the condition that Peking not use it for military purposes. *Mainichi Shimbun*, a Japanese daily newspaper, reported that the decision was made at a December meeting of the Foreign Ministry, the Ministry of International Trade and Industry and the country's Science and Technology Agency.

• **Babcock & Wilcox Canada** said it will supply eight nuclear steam generators for the first two 600 MW CANDU reactors owned and operated by Intreprinderea Nuclearo-Electrica Cernavoda of Romania. In addition, B&W Canada said it will train Romanian office and shop personnel in the manufacturing process and will eventually provide consultants to Romania for future domestic supply. The $50-million contract became effective in mid-January.

• **Atomic Energy of Canada Limited (AECL)** said it has licensed Pacific Nuclear Systems Inc. of Washington to market its dry-storage concrete cask technology. The cask is designed as a passive system capable of accepting light water reactor irradiated fuel, five years or older, utilizing readily available construction materials. The casks have been in use at AECL's Whiteshell Nuclear Research Establishment since 1976.

• **AECL** and the New Brunswick Electric Power Commission have notified the Atomic Energy Control Board that they plan to engineer and build a second CANDU 600 MW reactor at Point Lepreau, southwest of St. John, New Brunswick. In 1974, the board approved the site for two CANDU units.

• **The Canadian Nuclear Association** reports that from Oct. 26 to Nov. 15, last year, the Gentilly-2 nuclear unit of Hydro-Quebec was shutdown because of the illness of a single shift supervisor. It seems that the problem developed from a requirement that the utility's supervisory personnel speak French. Since the shift supervisor was the only one that was qualified, when he became ill, the plant had to be shutdown. Now, reports the association, two more shift supervisors are currently being trained.

• **Sweden's State Power Board** says it wants to build a 1,200 MW coal-fired plant in the Baltic Sea port of Oxelosund. The government is evaluating a comprehensive environmental impact report and project proposal. In addition to the power plant, plans call for enlarging the port so that it can handle 7.7 million tons of coal a year by 2000. *Sweden Now*, an international magazine promoting the country, reports that the plant may run into difficulty. The magazine says the power really isn't needed and the plant wasn't designed so that cooling water could be used for district heating. Both problems irritate the government, said the publication.

• **Mexico's** national electric utility agency, Comision Federal de Electricidad signed a power exchange agreement with Southern California Edison Company. The agreement will enable either utility to buy electricity from the other whenever the price is lower than the cost of producing the same electricity at its own power plants or purchasing it elsewhere.

In This Issue

Editorial 4

Calendar 9

Life extension programs for aging power plants are getting serious attention from the utility industry. 14

Heat rate improvements for existing plants and the next generation of new fossil-fired plants are targets of a new EPRI program.**G**. 24

A computer program for buying and selling power is helping San Diego Gas & Electric optimize its energy interchange.**T/D**. 34

New Products 37

Readers' Service 39

Bulletin Board 40

Regulatory Review 43

Personnel 44

Management Methods 46

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Rural America threatened by Reagan, warns NRECA head

SAN FRANCISCO—Policies of the Reagan administration "pose the greatest threat to agriculture and rural America that we have faced since the Great Depression," warned the head of the National Rural Electric Cooperative Association (NRECA).

Speaking before approximately 10,000 attendees of the NRECA annual meeting, Executive Director Robert D. Partridge said he saw no way to reconcile the views and convictions of rural electrification leaders with those of the administration "whose ideas faithfully track the 1981 OMB budget blueprint for phasing out the REA program."

President Reagan has opposed legislation supported by the group that seeks to raise interest rates on loans to rural electric systems, provide them with a permanent source of capital through the Rural Electrification Administration and permit the rural electric systems to refinance loans if interest rates drop.

Bipartisan support

Partridge said that there is strong bipartisan support in Congress for the rural electric financing legislation and he predicted that the bill would be passed.

"You have the fight of your lives ahead to protect the rural electrification program, revive rural development, and obtain decent farm credit and farm income programs," he told the rural leaders, "You had better gird for battle."

The NRECA head also reviewed the strengths and challenges of the rural electrification program.

He said, "We have derived great strength from the fact that we are non-profit systems, principally cooperatives, dedicated to service. Each of us has no other purpose than to provide service. We do not have to compromise to other purposes...We are not miniatures of investor-owned utilities and we'd make a grave mistake if we were to presume that we are."

Partridge pointed out that the inherent disadvantages of serving rural America are still there—low density and high investment in relation to revenue.

Delegates cautioned

Delegates were cautioned by Partridge to be "watchful, discerning and member-responsive" as they debate and develop policies that will guide them in the years ahead on such matters as the environment, federal power and reliable power supply sources.

Partridge has headed the association since 1968. In April he will be succeeded by former Secretary of Agriculture Bob Bergland. NRECA's membership includes 1,000 consumer-owned rural electric systems serving more than 25 million people in 46 states.

Acid Rain . . . from page 1

In an interview with reporters the morning after President Reagan's State of the Union message, Ruckelshaus said that the President did not believe an acid rain program was currently justified.

"The President is not persuaded at this point that we know enough to implement a major sulfur dioxide emissions program," said Ruckelshaus.

Insiders say that Ruckelshaus couldn't garner enough support for his plan among members of the President's Cabinet Council. Budget Director David Stockman and Energy Secretary Hodel were known to be adamantly opposed to any type of control plan at this time because of multi-billion price tags for a large cleanup.

EPA spokesman Chris Rice said there are no present plans for the agency to implement any emissions control program and that Ruckelshaus will fully support the President's position.

Others outraged

Environmentalists and Canadians were outraged by the call for more research.

"President Reagan ordering more research is akin to the captain of the Titanic ordering further measurements of the size of the holes before doing anything," said Dick Ayres, chairman of the National Clean Air Coalition.

Elizabeth Barratt-Brown of the Natural Resources Defense Council, an environmental lobbying group, said "Reagan is standing alone." She said the longer a control program is delayed, the greater the damage will be.

Brown said that the President has put the ball into the hands of Congress and she expects them to take some form of action on acid rain in the short time left in the term.

"Clearly, acid rain is one of the most pressing issues on Congress's agenda," said Barratt-Brown.

Canada's Environment Minister Charles Caccia said he was "shocked" by Reagan's decision to continue studying acid rain. For some time, Canadians have been pressuring Washington to do something about acid rain. They claim that Canadian lakes and streams are dying because of U.S.-originated acid rain.

Disappointed

"We are deeply disappointed by the failure of the United States government to take concrete action to deal with the problem of acid rain," stated Canada's Department of External Affairs.

Others, such as National Coal Association President Carl Bagge, disagreed. He said the President's decision displayed remarkable political courage.

"The President should be commended for refusing to yield to ill-advised demands for a multi-billion dollar program that will produce little or no benefit and for proposing direct action to deal with acified bodies of water," said Bagge.

Did You Hear...

"I can close my eyes and listen to somebody start to talk about acid-rain, and I can tell you within 100 miles where he or she lives." The clues: Westerners say they want acid rain cleaned up, but they won't pay for it. New Englanders say their lakes are poisoned and Midwesterners should pay for the cleanup. Midwesterners don't think there's a problem. And Southerners say, "It's your problem, don't bother us."

— EPA Administrator William Ruckelshaus on NBC News's "Meet the Press."

Can the utility industry find a fountain of youth for its aging generating capacity?

Robert Smock
Managing Editor

Utilities are beginning to get serious about power plant life extension. They've been talking for several years about spending money to extend the life of 30-year old plants another 30 years, but so far haven't committed much money to it.

Examples of pure life extension projects on old generating capacity are still few and far between, but the pace appears to be picking up.

If the trend develops it will be a significant change in the way utilities do business. Traditionally, fossil-fired capacity was retired when it was about 40 years old. Spending on aging power plants started to decline at about the 25-year mark as reliability deteriorated and such capacity was typically relegated to periodic operation, reserve status, and, ultimately, demolition.

Now utilities are thinking about spending several hundred dollars a kilowatt on old plants in order to get another 15, 20, or even 30 years of life. That's often more than the plants cost to build, but with new fossil capacity costing more than $1000 a kilowatt it might make sense.

Potomac Electric Power Co. recently announced that it plans to spend $79 million on extending the life of its 500-MW Potomac River station. Work has started on units 1 and 2, 92-MW each, which went into service in 1949 and 1950. Design goal for replacement component suppliers is 30 years more life.

"Because of high construction costs the company wants to defer for as long as possible the need to build new generating plants," said PEPCO president Edward Mitchell in announcing the project. "Plant life extension, along with our energy use management programs, will help us achieve this objective."

Most utilities considering life extension are still in the "study" phase. An example is Pennsylvania Power & Light Co. which hired Westinghouse to do a $1 million study of extending the life of a 343-MW unit at its Brunner Island station to the year 2010. Another example is Wisconsin Electric Power which hired Bechtel to look at extending the life of three units at a cost of more than $1 million per unit for the study.

Aging capacity

Life extension could become a significant trend in the industry in the '80s because of several underlying forces. One is the shift in average power plant age. Historically, only a tiny percentage of total utility capacity was a candidate for retirement. Exponential growth of 6 or 7 percent a year meant that half of all capacity was always brand new, less than 10 years old.

That pattern held until 1970. As shown in Table 1 half of all capacity in 1970 was less than 10 years old and only 2 percent was more than 30 years old. The slowdown in new capacity additions during the decade produced a slight shift in those percentages by 1980. However, by 1990 and 2000 there will be profound changes in the age characteristics of the U.S. power plant inventory.

For example, Westinghouse projects that by the year 2000 there will be almost as much 30-year old capacity as 10-year old capacity. Combustion Engineering's Mark Caron, manager of availability and reliability engineering, says this means that 694 coal-fired units, totaling almost 40,000 MW, will pass the 30-year mark in the next few decades. Of course, utilities could retire those old units but, for the first time in the history of the industry, the old units will represent a large and valuable asset.

Senior citizens

These senior citizens will be a large percentage of the total because of the new capacity addition patterns of the last 40 years. As shown in Table 2 growth in generating capacity spurted up sharply in 1950. Look at just the coal-fired plant column. During the 20's 2000 MW were added, 1500 MW in the 30's, 10,000 MW in the 40's, 50,000 MW in the 50's, and 100,000 MW in the 70's. The 50,000 MW added in the 50's, the first big block of capacity in the history of the industry, is just now approaching the traditional end of life and utilities must decide what to do with it.

TABLE 1
AGING GENERATING CAPACITY

	Percentage of utility generating capacity that is:	
	10 years old or less	More than 30 years old
1970	50%	2%
1980	45%	8%
1990*	30%	15%
2000*	26%	23%

*Assumes all currently planned plants are completed.
Source: Westinghouse

That pattern will continue into the future because utilities have cancelled so much of the capacity that was to have been added in the 1980s and 1990s. Since 1975 order cancellations have topped new orders by more than 50,000 MW. That's why new capacity will constitute a smaller percentage of the total inventory for the next 20 years and capacity more than 30 years will grow in importance.

In addition, that large block of old capacity is more valuable than 20's and 30's vintage capacity. It was in the fifties that average new unit size topped 100 MW for the first time in industry history and heat rates got down to the 10,000 range. Older capacity has relatively tiny unit sizes and heat rates approaching 20,000 in some cases.

It was easier to decide to retire plants that used obviously obsolete technology. The capacity now crossing the 30-year line is not obsolete. Efficiency and reliability of fossil-fired generating capacity has not advanced much, if any, over the past 30 years. In fact, old capacity burning high-sulfur coal without a stackgas scrubber may look attractive to some utilities compared to new capacity requiring a scrubber.

The overriding consideration, however, is cost. In order to continue to operate 30-year-old plants some refurbishing is necessary because, otherwise, the forced outage rate would rise rapidly. The cost of such refurbishment can be much less than the cost of new capacity.

Deferring new capacity

Potomac Electric Power Co. has committed to a strategy of power plant life extension in order to defer the need for new generating capacity. The utility has been surveying its older capacity for the past two years and recently announced a $79 million revamping of its Potomac River station. The station is PEPCO's oldest. It has two 92-MW units built in 1949 and 1950 and three 110-MW units built in 1954, 1956, and 1957.

Goal of the modernization project is to extend the units' life "as long as is economically and technically possible," says Bob Carelock, project engineer. The design goal that's being used is an additional 30 years, he adds. That's the number PEPCO gives suppliers who need a target. As a practical matter, the utility doesn't know how long the units can ultimately last, says Carelock.

The issue is economics. How much is worth spending. An equivalent amount of new capacity would cost PEPCO $635 million, so the $79 million (in 1983 dollars) for upgrading the Potomac River station was felt to be justified.

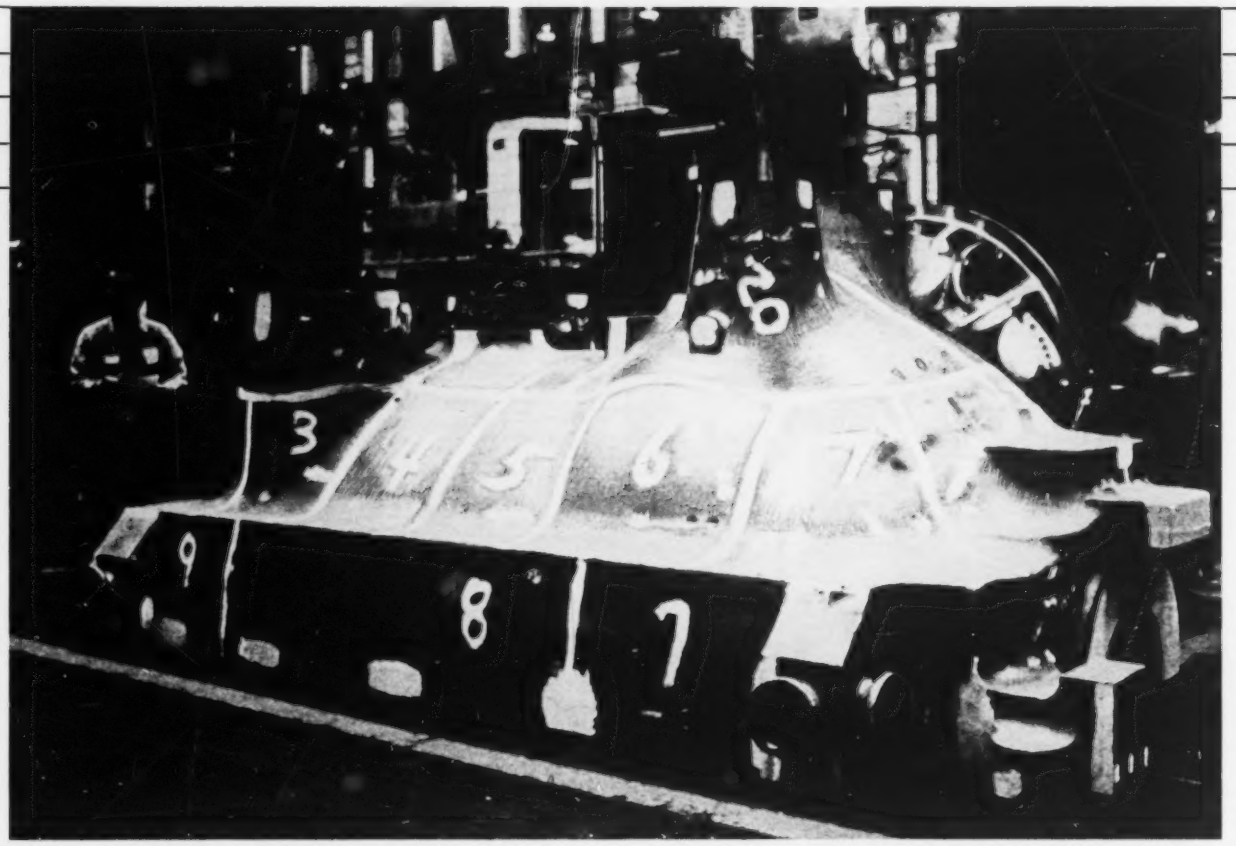
The work will be done in stages over the next 10 or 12 years. At each unit's annual two-month scheduled outage a portion of the work will be done. In January unit 1 was down for the first step of its rebuilding. Focus was on boiler work, including replacement of the high temperature superheater, tubular air heater elements, and the lower section of the economizer. Additional boiler work and replacements of other components will be done in future outages. In April the first stage of work is slated to begin on unit two.

Carelock explains that PEPCO has been surveying company capacity and studying the potential for life extension for the past two years. Company engineers have overseen the work but specific portions have been farmed out to the original equipment suppliers, Combustion Engineering on unit 1 and 2 boilers and GE for the turbine generators.

The inspections showed that several PEPCO stations are, or will be, candidates for life extension. Most of the refurbishing will be done on the boilers, as described. Some stations will need new pulverizers, outer turbine casings will have to be replaced in a few cases, and some generators will require rewinding. Carelock says control systems are still being surveyed with an eye to upgrading obsolete, decentralized systems that are unwieldy to operate and for which spare parts are no longer available.

The Potomac River station project is the first of its kind on the PEPCO system, says Carelock. Previous plant upgrading projects have been done to achieve a goal other than life extension—a balanced draft conversion project at the utility's Chalk Point station, for example. Next PEPCO candidate for life extension will probably be its Dickerson plant.

PEPCO expects system peak demand to grow at an annual rate of 1 to 2 percent for the next 10 years. Life



GE says a complete turbine shell replacement can be useful in a life extension project because modern designs have a lower cracking rate.

extension is expected to put off the need for new capacity until the mid to late 1990s.

Studying life extension

Pennsylvania Power & Light is an example of a company that's seriously considering life extension but hasn't yet committed to a large capital program. Given less-than-forecasted load growth, a nuclear station in the final stages of construction, and healthy reserve margins, management decided that the utility should not commit to any new generating capacity for the indefinite future. In order to provide insurance, a formal program to protect existing capacity and extend its life was launched.

Tom Yezerski is manager of the fossil plant extended life program at Pennsylvania Power & Light Co., a job that didn't exist at his company until 1982, and still doesn't exist at most utilities. "We don't have a lot of data yet, but compared to other utilities who aren't sure they want to do this, we're ahead," says the manager.

No major renovation projects have been started yet, but Yezerski feels that an investment as high as $1000 per kW might be justified.

First step in the program was a "health exam" for all the utility's generating stations. Goal is a prescription of actions to take to achieve the desired effect, which ranges from extending the plant life indefinitely to improving plant efficiency, raising output, or converting it from base load to cycling operation.

Most of the checkups are being done in-house, but one, at the utility's Brunner Island station, was farmed out to an outside contractor, Westinghouse, as a test case. Yezerski said Westinghouse was asked for recommendations to extend the life of one 343-MW unit at the plant to the year 2010 and to change its duty cycle so it could turn down as low as 50 MW on a daily basis.

In a preliminary report Westinghouse said it would cost $32 million to achieve both goals and $20 million for the life extension alone. Westinghouse concentrated on the turbine generator and brought in Combustion Engineering to look at the boiler. New equipment such as a high-pressure turbine casing and a new boiler roof were recommended. Yezerski points out that the unit is now running fairly well and there is no immediate need to renovate it. The purpose of the Brunner Island study and the in-house studies is to assess where the utility is right now and plan the future in a systematic way.

As at most utilities Pa P&L has always had an active maintenance and betterment program for its existing plants, Yezerski explains. The utility has currently committed to a total of $43 million worth of such projects, a combination of maintenance and upgrading at most of its plants. Some of these projects, such as renovating boilers at two 130-MW units and an 80-MW unit, could fall under the life extension program. There's still a lot of overlap.

Yezerski explains that the new program is not intended to be traditional maintenance and that part of the learning process is to determine how to treat capitalized upgrading and life extension projects differently from conventional, expensed operation and maintenance projects.

So far the life extension survey at Pa P&L has identified $118 million in 55 projects at 14 steam plants and 12 hydro plants totaling 4500 MW. None of these has been committed yet. Yezerski says the utility is not close to a commitment to a major renovation. For one reason, it doesn't have to, and there are too many unknowns remaining. "It's not just a simple economic decision," he adds.

Another utility that's doing formal studies is Wisconsin Electric Power. The company is spending "more than $1 million per unit" for life extension studies by Bechtel. The focus is on typical units at each of its three old coal-fired stations, reports operations vice president Ken Walters. The studies are being done on the 80-MW, 1948-vintage Port Washington unit 3, 120-MW North Oak Creek unit 1 (1953), and a 250-MW, 1959 vintage unit at its South Oak Creek station.

Milwaukee-based WEPCO is in a situation of uncertain load growth, a fairly large reserve margin, and a capacity expansion program ending in 1985 with the completion of the 600-MW Pleasant Prairie unit 2. Questions to be answered in the life extension study, says Engineering Vice President Huberto Platz, are, Is it feasible to extend the life of typical units at these stations to 2010? and, What would be required and what would it cost? Future capacity expansion plans will depend, to some extent, on the results of the life extension studies.

WEPCO's experience gives some insight into a utility's retire/renovate decision. The company recently retired its 1920's-vintage Lakeside station which had 350 MW spread over 14 oil-fired units, none larger than 60 MW. Fuel cost and manpower cost of continued operation of that plant were felt to be prohibitive, so it was retired, relates Walters. At the other end of the spectrum is the utility's Valley station with two 136-MW coal-fired units. Since they were installed in 1968 and 1969, there's no need to consider them for life extension.

WEPCO hired Bechtel to do the studies, says Walters, because it wanted a plant-wide, systems approach: "We could have gone to equipment vendors but we felt a firm like Bechtel has a broader knowledge of combined systems. It's more than just individual components. We're interested in the whole system." The study started in May, 1983. The investigative phase is complete and preliminary findings are now being presented. Final report is due in late June of this year.

Still building nukes

Even utilities in the middle of large nuclear construction programs are looking at life extension. Duke Power Co. has conducted formal surveys of two stations with 30-year old units (Dan River and Allen) by its own engineering staff. Duke is still in the middle of a nuclear construction program. Its McGuire unit 2 is slated to go into service this spring and two units at the Catawba station are under construction and scheduled to go into service in 1985 and 1987. That, however, is the end of the company's construction program and it wants to make sure that it is taking any necessary steps now to insure that loads will be met in the late 80s and 90s. Duke is still evaluating the studies and has not committed any capital to life extension projects.

Gas-fired capacity

Life extension appeals to different utilities for different reasons. Consider Oklahoma Gas & Electric, a utility that hasn't committed any money to life extension, but is thinking seriously about it.

Traditionally a gas-fired utility, OG&E began a coal-fired, base-load plant construction program 10 years ago and now is about half and half. Its gas-fired capacity was threatened by the Carter Administration's Fuel Use Act which said utilities would have to shut down base-loaded gas-fired capacity by the 1990s. That federal law was repealed however, and now OG&E is looking at its gas fired capacity in a new light.

Some utilities with gas-fired plants are opting to convert them to coal (Tucson Gas & Electric, for example) or replace them with new coal-fired plants and shut them down. OG&E, however, is located in the middle of the gas supply region and utility executives are confident that they know how to buy gas and keep it relatively inexpensive. Chairman James Harlow said, in an interview last fall, "I think we'll be burning gas into the next century if we can keep those units running. We're studying the possibility of life extension of those gas-fired plants."

OG&E Vice President Merril Hines said that life extension of gas-fired capacity will probably be cost-effective. Goals of an upgrading program would be to convert gas-fired capacity to handle intermediate, cycling-type duty, to restore original heat rates, and to extend plant life. First candidate may be a 30-year old, 74 MW unit at the utility's Arbuckle power plant.

The modernization project would have to prove cost-effective compared to buying new peaking/intermediate generating capacity at about

$300/kW, Hines explained. He added that there are some non-cost factors in favor of refurbishment. For example, federal law restricts new gas-fired generating capacity to 1500 hours of operation per year. A modernized existing plant would have no such limit. Also, a new plant would require a costly and time-consuming siting process while the old plant is already on an approved site.

Hines said that a decision will have to be made for capacity that is about 35 years old, the expected life for OG&E plants. "If you don't do something," he explained, "you know that you'll be getting close to the life of some components in the plant. We don't feel we can continue to operate the old plants and consider them dependable capacity."

Not all OG&E's gas-fired plants are candidates, explained Production Vice President George Gibbons. Some are just too old or have special problems. For example, the utility retired its Belle Isle peaker plant because an environmental restriction on cooling water temperature limited its operation to winter months. Another plant, the Osage station was retired because it had an average heat rate of 17,000. That was OK when gas cost 18 cents a million Btu, but at today's prices, said Gibbons, "You can't stand that." Two other units of 1928 vintage, Muskogee 1 and 2, also had heat rates too high to warrant rebuilding them.

Gibbons says OG&E's Arbuckle station is a good test vehicle for the concept of life extension. It is not too small or too old, so OG&E hired a consultant to make a study. "We're approaching it very cautiously," says the executive.

Funds are available

Another utility that's committed to protecting its investment in existing generating capacity and extending its life is Virginia Electric & Power Co.

Power station Engineering Vice President Bill Spencer explained management's philosophy at last fall's Joint Power Generation Conference. "Funds are available and people are available" for work on the older power plants because other major capital projects are finished.

"We've completed a nuclear program—we built four and cancelled four," Spencer explained. A costly program of replacing steam generators at one nuclear station has also been finished. The next step was to reduce the company's reliance on oil fuel through a massive coal conversion program that is now largely complete. As a result of this activity rates have been relatively flat for the past few years, and VEPCO management wants to keep it that way.

Concentrating on maintaining or improving the operating performance of the existing capacity is perceived as the best way to continue to hold rates down at VEPCO. Some modernization projects on old capacity have already been completed. For example, two units built with forced-draft boiler systems whose performance was not good have been converted to balanced draft. Two more are being converted.

Spencer said VEPCO currently has 300 retrofit and improvement projects under way at nuclear and fossil plants. The projects are keeping 460 engineers busy, 300 of them VEPCO's.

How are projects picked? Spencer says VEPCO started out by doing payback analyses, but quickly moved beyond that. Under the utility's rate structure most of the benefits of efficiency or output improvements flow through to the customer in the form of fuel cost adjustment reductions.

TABLE 2
MEGAWATTS OF NEW U.S. CAPACITY

	Unit Type						
Years	Coal steam	Gas steam	Hydro	Lignite steam	Nuclear	Oil steam	Total*
1900-1905	0	0	116	0	0	0	126
1906-1910	0	0	507	0	0	14	521
1911-1915	0	6	850	0	0	86	942
1916-1920	72	191	865	0	0	439	1,582
1921-1925	676	376	1,778	0	0	556	3,452
1926-1930	1,303	927	2,432	10	0	1,533	6,305
1931-1935	241	119	871	8	0	942	2,411
1936-1940	1,308	532	2,677	12	0	1,287	6,134
1941-1945	2,942	617	2,885	0	0	2,344	8,920
1946-1950	6,714	3,130	2,372	122	0	6,176	19,140
1951-1955	24,123	5,811	6,319	88	0	11,376	48,147
1956-1960	25,738	8,908	8,922	105	287	12,602	57,016
1961-1965	23,341	8,301	12,159	151	566	15,359	62,474
1966-1970	43,076	17,084	6,997	619	4,905	10,186	96,754
1971-1975	55,918	16,550	4,963	3,178	30,789	20,665	161,938
1976-1980	52,766	2,942	8,925	5,943	17,042	15,382	113,674
1981-1985	53,843	0	2,666	6,530	49,398	2,892	126,332
1986-1990	21,075	0	68	1,560	30,615	444	58,122
1991-1995	1,100	0	0	0	8,526	800	10,696
Total	314,236	65,494	66,372	18,326	142,128	103,083	784,686

*Total includes combined cycle, gas peaking, internal combustion, and pumped hydro, which are not shown.
Source: DOE

TABLE 3
AVERAGE AND WEIGHTED AVERAGE AGE

Type of unit	Number of units	Total capacity (MW)	Average age (years)	Weighted average age (years)
Coal steam	1,352	255,197	23.6	13.2
Oil steam	794	99,175	28.9	17.9
Gas steam	683	63,708	27.4	17.4
Lignite steam	38	11,382	16.9	5.9
Nuclear	91	72,736	7.2	5.8
Combined cycle	86	6,788	8.8	7.5
Oil peaking	839	31,199	11.2	10.2
Gas peaking	208	6,453	11.7	9.7
Internal combustion	2,302	3,922	27.2	22.1
Hydro	2,642	64,768	45.7	24.1
Pumped hydro	130	14,436	11.4	8.1

Source: DOE

"Cost-benefit analysis is not possible on all projects," said Spencer. "You just have that gut feeling you should do it." Capital investments are justified, even if returns don't flow straight through to the shareholder, if they can serve to hold down rates, Spencer added.

Equipment suppliers

Major equipment suppliers are encouraging the life extension trend because it provides them a market for goods and services in the absence of a new plant market. Westinghouse, for example, has been marketing turbine-generator upgrades for several years and now has launched a comprehensive plant modernization program. "Utility managers' desks are piled high with proposals for modernization of individual pieces of equipment," says T-G division Marketing Manager Kenneth Oleson.

In order to develop a total plant approach that would be more welcome to utility executives, Westinghouse intends to join forces with A-Es and boiler suppliers. As mentioned above, the first such study, with Combustion Engineering, was done for Pennsylvania Power & Light Co.'s Brunner Island station. The utility is now evaluating it.

The modernization work Westinghouse has been doing on turbine-generators for the past five years or so has been focussed on converting from base-load to cycling operation. The trend now is pure life extension of the entire plant, says Oleson. For the next year or so the utility industry will continue doing studies and capital spending should begin in a major way in 1985 or 1986, Oleson guesses. "They're going to want to feel comfortable about our ability to accurately predict the life of components and extend the life of the plant."

The goals of a Westinghouse plant modernization project are to extend the life of a plant another 20 or 30 years, says Oleson, and to improve plant performance. Performance guarantees are part of the package, he adds. Secondary benefits include improved plant availability and factors like changing the plant from base-load to cycling.

Oleson says the potential utility market over the next 10 years for turbine island modernization alone is $10 billion.

Power plant life extension also represents a huge potential market for boiler suppliers. Norman Freeman, director of maintenance engineering and repair for Foster Wheeler, sees boiler "aftermarket" business doubling over the next few years. Right now utilities are showing interest in major boiler life extension studies, says Freeman, but they're spending money on fairly conventional maintenance services. Foster Wheeler is seeing an increase in its annual contract power plant overhaul business. This is long-term, pre-planned maintenance, Freeman explains.

"There are a lot of studies and a lot of talk about extending the life of power plants," says Freeman, "but utilities aren't spending a whole lot yet." Foster Wheeler is currently doing the boiler inspection on Wisconsin Electric Power Co.'s Oak Creek station.

With new fossil capacity costing $1200 to $1500 a kW, it may make sense for utilities to spend a few hundred dollars a kW on old capacity to upgrade it to its original capacity or improve it with new hardware and technology, Freeman says. He notes that this work can be done quickly, usually in less than one year, allowing utilities the luxury of putting off a decision on life extension until load-growth trends and capacity expansion plans become clearer.

TVA life extension

Foster Wheeler has already completed a major boiler upgrading job at TVA that could be included in the life extension category. The job was done on four 150-MW coal-fired units at the Johnsonville station. TVA decided to rebuild the boilers of these 25-year old units because a predicted boost in availability led to a capital cost payback time of only 4.5 to 5 years, according to utility engineer Charles Dammann. Life of the boilers was also extended an estimated 15 years.

Availability deterioration was the main reason for the Johnsonville upgrade. Between 1960 and 1972 availability at the four units average 90 percent. Between 1973 and 1976 it dropped to 81 percent. TVA and Foster Wheeler, which supplied the boilers, then did an inspection and engineering study that determined that a boiler rebuild could solve the problem. The rebuild started in the spring of 1981. Each unit was scheduled to be out of service for 26 weeks. The job was completed last April. Since then forced outages were "nil" and there's been a "substantial increase" in availability and reliability, according to TVA and Foster Wheeler.

Costly new capacity

Economics is driving the life extension trend, according to Combustion Engineering's Mark Caron. Today's 30-year old capacity cost only $100/kW to build, he pointed out at the Joint Power Generation Conference. New coal-fired capacity now costs $1200-1500/kW. New capacity also faces siting and environmental problems that can be sidestepped with rebuilt existing capacity.

CE's analysis of aging power plants shows that plants, boilers in particular, enter a "wear-out" phase in which component failure rates climb sharply. The goal of a life extension program is to eliminate that phase.

H. Kerner Smith, manager of fossil power systems for Babcock & Wilcox's utility power generation division told the conference that 60 percent of the fossil units in the U.S. are more than 20 years old. Many of these units are or will be used for cycling duty. Said Smith, "These units weren't designed to do what you're doing to them." Boiler suppliers see an opportunity to upgrade this capacity for cycling operation. Right now utilities seem to be waiting, to finish their existing capacity expansion programs, to see how much acid rain regulations cost them, and to watch load growth.

Smith said B&W work on old plants has included fuel conversions, cycling

Continued on next page

Life extension . . . from page 16

modifications, boiler pressure part replacements, and capacity restorations and half a dozen coal-fired plants that switched to lower-grade fuels. Starting point is a boiler fitness survey, a "health scan" of boilers.

Riley Stoker Co. has also been active in the business of modernizing old boilers. Examples of the firm's recent work are installation of new superheater and waterwall tubing at Texas Electric's 20-year old Handley unit 3, replacement of waterwall panels at PEPCO's Dickerson station, and superheater modification at Texas Electric's 20-year old generating Graham station.

Control systems

Control system modernization is a popular specialized form of upgrading at power plants. Frank Ryan, applications engineer for Leeds & Northrup, says that utilities with obsolete control systems are prime candidates. There are many power plants with controls supplied by companies that have gone out of business or using hardware that is no longer available. Utilities are unable to maintain these systems or even buy spare parts.

That obsolescence, plus the new distributed digital technology that is sweeping in, has led many utilities to tear out the old and put in completely new systems. Modernization is a very active business for controls suppliers, says Ryan. "It's virtually the only business there is right now," he adds.

Some of the projects are part of larger, comprehensive plant upgrading projects but many utilities are focussing in on just the control systems in old plants they want to operate longer.

Ryan describes a control system upgrade project recently completed at LILCO's 10-year old Northport unit 3. An analog combustion control system was replaced with an L&N microprocessor-based digital control system.

L&N has a project currently underway at Philadelphia Electric's 20-year old Eddystone and 30-year old Cromby stations. Eddystone has an old hydraulic control system for the feedwater heating cycle that is being replaced in the first phase with a digital system.

"Virtually all modern control systems wind up digital," says Ryan. Utility operating people start out talking analog electronic because there is generally "not a positive perception" of anything digital, he explains. But when they look at the new control technology and the results it's achieved, at installations such as LILCO, they are convinced to go with digital microprocessor-type controls.

Ryan points out that new plants and modernization projects are still going in with analog controls, but that's because the control system commitment was made before the microprocessor revolution of two or three years ago. The newer units are committing to distributed digital controls. L&N just shipped digital hardware for New York State Electric & Gas Co.'s new Somerset station. Another customer, Northern States Power committed to distributed digital control for its Sherburne 3 unit.

"Everything we've bid in the last two years has been microprocessor-based DDC," says Ryan. Buyers may start out talking analog but "when the chips are down" and they have to make a commitment, they're going distributed digital.

The new technology is helping the modernization business because it allows utilities to do things not possible 20 years ago due to hardware limitations, says Ryan. For example, automatic load control can be improved substantially. In many old power plants the response of the unit to command pulses sent by the dispatcher is unpredictable. The unit may change load at the intended rate, it may not change at all, or may change too fast, says Ryan. New hardware can close that loop at the power plant and make it much more reliable. There are major benefits in economic dispatch, says Ryan, at a control system cost that's "not that great."

First look taken of TMI-2 core samples

MIDDLETOWN, PA—Preliminary examinations have been conducted on the first samples of the damaged TMI-2 fuel core, said GPU Nuclear.

Radiation measurements from two of the samples produced readings of one rem an hour, gamma, at a distance of one ft from one of the samples and five rem an hour, gamma, on contact from the other, said GPU.

Last fall, six samples were taken from two locations in the core. One was at the center and the other at a point midway between the center and the core's edge. At each point, a sample was taken from the rubble bed surface and at depths of two inches and 22 inches below the bed's surface.

GPU Nuclear said the samples ranged in size from particulate matter less than four one-hundredths of an inch in diameter to "rock-like" pieces six-tenths of an inch in diameter. This means, explained the company, that plans to remove a majority of the core with vacuuming equipment can be carried out.

The larger pieces help to confirm the utility's belief that the rubble bed was created when overheated fuel assemblies shattered after being suddenly cooled by water. The sample particles are mostly brown and black, said GPU.

The samples also gave GPU Nuclear further proof of the melting of some stainless steel components and other metals with lower melting points. Stainless steel has a melting point of 2,550 Farenheit to 2,600 F. The utility said its preliminary examinations have produced no evidence of melted uranium oxide fuel, which melts at 5,080 F.

Additional examinations

Additional examinations to obtain further information on the radiological and chemical nature of the debris samples will take several months to finish, according to the utility.

Build the best utility vegetation control program on a cornerstone of Banvel® products.
herbicide

When you choose Banvel® herbicide products for utility vegetation management, you . . .

- Leave native grasses intact.
- Get cost-effective results.
- Spray materials that are environmentally sound when used as directed.
- Control the broadest spectrum of broadleaf weed and brush species.
- Choose from a wide variety of approved tank-mix options.

Talk to your Velsicol representative and find out why Banvel herbicide products are the best way to build utility vegetation management programs that fit all your needs.

Banvel® herbicide products.
Your cornerstone of vegetation management

VELSICOL CHEMICAL CORPORATION

Banvel® is a registered trademark of Velsicol Chemical Corporation.
Read and follow label directions carefully.

Inquire R.S. 6

Operating unit heat rates can be cut, says EPRI; new units can be 10% more efficient

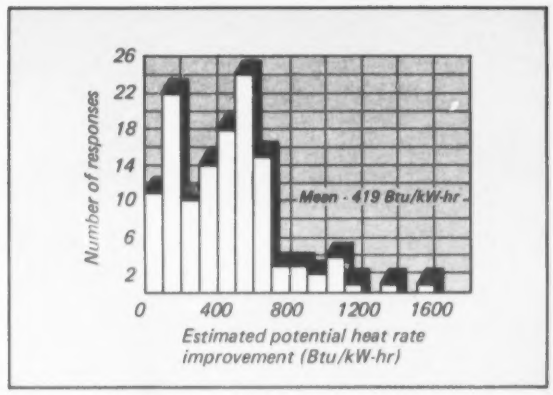


Fig. 1. Survey of heat rate improvements.

Robert Smock
Managing Editor

A one percent improvement in the heat rates of many existing fossil-fired plants is "easily attainable," according to EPRI's manager of power plant systems and performance, Tony Armor. Fuel savings over the next five years resulting from such a gain would be worth $700 million.

Armor focussed on heat rate improvements in a presentation at last fall's Joint Power Generation Conference on EPRI's programs to improve the performance of existing plants.

"New plants, nuclear or fossil, will be few and far between until the year 2000," Armor said, adding, "That increases the importance of operating the existing ones." He pointed out that there are 1000 fossil-fired units in operation that are 100 MW or larger in size. The developing trend to extend the life of some of these aging plants (see related story beginning on page 14) should include an effort to improve heat rates, Armor said.

Room for improvement

That's because there's so much opportunity for improvement. Looking at fossil system heat rates, Armor said, "There's a huge disparity between the best utilities and the worst." Displaying *EL&P's* list of the 20 most efficient units operated by the 100 largest investor-owned utilities as shown in Table 1, Armor said the performance of Duke Power's Marshall station can serve as a benchmark for other utilities.

He said the goal of EPRI's programs is to achieve a 3 percent gain in the performance of older units.

One incentive for effort in this area is growing pressure from state regulators. Armor claimed that all but 15 PUCs have added power plant operating incentives, in the form of rate penalties, for factors such as heat rates, availability, capacity factors, and forced outage rates. This trend developed in the last few years.

He reported results of a survey that shows utilities feel they can get a substantial improvement in their existing units' heat rates. The survey covered 120 units operated by utilities interested in heat rate improvement programs. It showed that heat rates at those stations were, on aver-

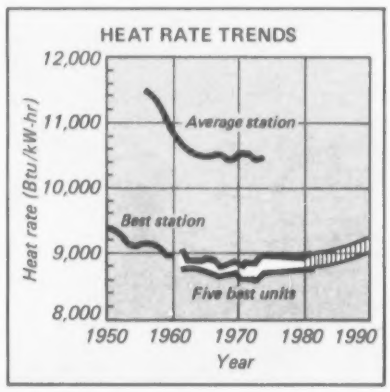


Fig. 2. The historical improvement in power plant heat rates stopped in the early 1960s.

age, 1000 Btu/kWh higher than the design level. The range was 100 to 3250 Btu/kWh.

The survey also determined how much of that loss was recoverable, in the opinion of the respondees. The range of results is shown in Figure 1. The mean saving is 419 Btu/kWh.

Estimates of where the improvements could come from were also turned up. For example:

- A one-inch (Mercury) improvement in turbine backpressure was judged to be worth 200 Btu/kWh.
- A 10F drop in flue gas temperature is good for 36 Btu/kWh.
- A one percent cut in excess oxygen is worth 30 Btu/kWh.

Another area targeted for EPRI research programs is on-line performance monitoring. Investigation of efficient stations—Duke's Marshall and Belews Creek plants, TVA's Bull Valley station, and AEP's Amos plant—shows that continuous monitoring of component performance is important to success.

EPRI feels that on-line performance monitoring technology needs to be improved and that instrumentation is a particular problem. A project is being developed to demonstrate the state of the art in monitoring at Potomac Electric Power Co.'s 575-MW Morgantown unit 2. Subcontractors included Power Technologies Inc., Lehigh University, and Combustion Engineering, Inc. The demonstration is expected to be completed in late 1985.

EPRI is also interested in improving the efficiency of new plants. Armor recounted how the historical improvement of power plant efficiency stopped in the early 1960s, as shown in Figure 2.

"I hesitate to say there's little new," Armor told the conference, "but the industry stopped producing innovations for the last 20 years." He cited the end of orders for supercritical-pressure units as an example.

EPRI feels, as a result of a two-year study by two design teams, that an "advanced" plant could be a whopping 10 percent more efficient than the best now being offered.

An essential part of that design would be supercritical pressure, according to Armor. He pointed out that every new fossil plant being built in Japan has a supercritical cycle. They're going in now with steam conditions of 4500 psig/1050F/1050F/1050F. By the year 2000 Japanese utilities will move to 5000 psig/1050F/1100F/1100F.

By then, Armor added, the Japanese intend to be the leaders in power plant design. With dim U.S. market prospects discouraging research by U.S. hardware suppliers, EPRI hopes to fill the gap.

Typical steam conditions for contemporary U.S. plants are 2600 psig/1005F, although there are a few new ones at 3850 psig. Armor feels the next generation of U.S. plants should have double reheat supercritical cycles, as in Japan, with sliding pressure capability. Specs from the two design teams are shown in Table 2.

Armor noted that many double reheat supercritical units were installed in the U.S. in the 1960s, but none have been ordered since then. "Why did we take a backward step?" he asked.

The EPRI official doesn't feel that supercritical-pressure units deserve the bad availability rap they've gotten. He claimed that initial problems have been overcome and that the supercritical units now in operation in the U.S. have average availability equal to that of the average subcritical unit. The latest generation of supercritical types, he added, are far superior in availability to the latest generation of subcritical units.

Armor claims the EPRI studies are turning around the thinking of U.S. utilities, who showed no interest in supercritical pressure a few years ago. He notes that half the units now on the drawing boards will have supercritical pressure cycles.

The EPRI studies show that the added capital cost to achieve 10 percent higher efficiency is justified by fuel cost savings for baseload (4000 hours) plants. Lifetime savings as high as $159 million were estimated. Armor noted that Japan's higher fuel costs make more efficient cycles easier to justify.

TABLE 1
TOP 20 GENERATING UNITS--BY HEAT RATE

	Unit	Capacity	Utility	Unit heat rate
1.	Marshall 3	630 MW	Duke Power	8901
2.	Marshall 4	630	Duke Power	8910
3.	Belews Creek 2	1120	Duke Power	8930
4.	Belews Creek 1	1120	Duke Power	8966
5.	Marshall 1	320	Duke Power	8991
6.	Marshall 2	320	Duke Power	9032
7.	Gorgia 10	883	Southern Company	9039
8.	Trenton Channel 9	500	Detroit Edison	9066
9.	Bay Shore 4	215	Toledo Edison	9127
10.	Canal 1	568	Commonwealth Energy	9180
11.	Morgantown 2	582	Potomac Electric Power	9295
12.	John Amos 2	800	American Electric Power	9305
13.	Mercer 2	306	Public Service Electric & Gas	9318
14.	Brayton Pt. 3	643	New England Electric System	9320
15.	Montour 2	750	Pennsylvania Power & Light	9351
16.	Bay Shore 1	136	Toledo Edison	9362
17.	Bay Shore 3	142	Toledo Edison	9375
18.	Big Sandy 1	260	American Electric Power	9379
19.	Fort Myers 2	367	Florida Power & Light	9391
20.	Monroe 1	750	Detroit Edison	9392

TABLE 2
ADVANCED PLANT GENERAL SPECIFICATIONS

	General Electric, B&W Team	Westinghouse, C-E Team
Gross rating, MW	725	824
Auxiliary power, MW	51	51
Net rating, MW	674	773
Auxiliary power, % of gross	7.0	6.2
Turbine heat rate, Btu/kWh	7300	7180
Net heat rate, Btu/kWh	8675	8330
Net thermal efficiency, %	39.5	41
Throttle pressure, psig (MPa)	4500 (31)	4500 (31)
Throttle temperature, °F (°C)	1050 (566)	1100 (593)
Throttle flow, Mlb/hr	4.4	5.1
1st reheat temperature, °F (°C)	1075 (579)	1050 (566)
2nd reheat temperature, °F (°C)	1100 (593)	1050 (566)
Final feedwater temperature, °F (°C)	580	604
Number feedwater heaters (incl. deaerator)	8	9
Condenser backpressure, in. Hg.	1.5	2.5
Turbine last stage length, in. (cm)	33.5 (85)	31 (79)
Generator efficiency, %	98.7	99.1
Boiler thermal efficiency, %	89.6	89.3
Excess combustion air, %	17	15
Air preheater exit gas temp., °F (°C)	300 (149)	270 (132)
FGD inlet gas temperature, °F (°C)	235 (113)	220 (104)
FGD exit gas temperature, °F (°C)	120 (49)	120 (49)
Stack gas temperature, °F (°C)	170 (76)	170 (76)

NOTE

ONLY THE FOLLOWING PAGES OF THIS

PUBLICATION HAVE BEEN FILMED

Cov. 1, 2-3.

4/5/84
C8650-4A

Volume 62, Number 4
April 1984

09435 1984301 W 2 2044
SUITE 800 COPY # 1
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Regulatory advocacy hit in NARUC probe of EEI funds

Dan Utroska
Associate Editor

WASHINGTON, D.C.—The Edison Electric Institute has revised upwards its figures on the amount it spends on legislative lobbying.

In response to an on-going probe by the National Association of Regulatory Utility Commissioners, EEI now says it actually spends 20 percent of institute expenses on such activities, rather than the 14 percent it had earlier estimated and reported to NARUC.

In addition, EEI states it spends 15 percent on regulatory activities. According to NARUC, this brings to 35 percent of institute expenses activities that are related to legislative lobbying and advocacy support and thus stand potentially to be disallowed from being passed along to ratepayers.

The association of regulators has decided to look into EEI expenditure in its effort to provide some generic guidance to state commissions when these are faced with the issue of determining how much of utility contributions to EEI are legitimately collectible from ratepayers.

In a preliminary report issued late last year, NARUC, lamenting that it was not getting full cooperation from EEI in gathering needed data, said it was forced to make "judgment" allocations on how much of EEI dues should be charged to ratepayers and how much to shareholders (see *EL&P*, February 1984, page 1).

"It is our judgment that one-quarter to one-third of EEI dues payments by member utilities should be borne by the shareholders," NARUC said in its preliminary report. This figure was immediately contested by EEI; the institute's Douglas Bauer called it "a number in the air" and "an arbitrary judgment."

Now EEI has issued its actual 1983 "disaggregations" showing that 2 percent of its expenses go for strict lobbying, 18 percent for broad support of legislative activities, and 15 percent for regulatory activities. These figures, which total 35 percent, are seen by NARUC as confirmation that its estimate of up to 33 percent as potentially disallowable were right on target.

Understandably, EEI not only contends that the 20 percent of EEI dues should be allowed expensed, but argues that even if this is not recommended, regulatory functions are a different activity entirely and therefore certainly not disallowable.

Addressing EEI regulatory func-

Continued on page 55

Met Ed plea bargain accepted

HARRISBURG, PA—Metropolitan Edison Co. pleaded guilty in Federal court to a criminal charge that the utility operated Three Mile Island Unit 2, over a six-month period, with an inaccurate and unreliable water inventory testing procedure.

In a plea bargain struck with U.S. Attorney David D. Queen and approved by Federal District Judge Sylvia Rambo, Met Ed agreed to pay $45,000 in fines. The utility pleaded no contest to six charges and four others were dropped.

As part of the agreement, Met Ed said it will provide $1 million for an emergency planning fund for the five county area around TMI. The company said it will not claim the sum for either tax or rate-making purposes.

Last November, Queen announced the 11-count indictment after the conclusion of a three-year grand jury investigation.

First Assistant U.S. Attorney James West said Met Ed pleaded guilty to a regulatory violation that is a criminal felony under the Atomic Energy Act.

General Public Utilities Corp., holding company for Met Ed, said it will ask the court to make public the evidence and grand jury records of the case, so the Nuclear Regulatory Commission can conclude its own investigation.

GPU Chairman and Chief Executive Officer William G. Kuhns said, "The indictment was settled because it would not serve the purpose of either the company or the government to go through the costly and lengthy process of a trial and possible appeals."

"Put very simple," admitted Kuhns, "the behavior identified by the U.S. Attorney relating to the water inventory tests (leak rate tests) was totally unacceptable. There can be no question about that."

In a 20-page statement of fact submitted to the court by the U.S. attorney, the government said that virtually "every record" concerning the

Continued on page 8

'We prevented a blackout': WSCC

Load shedding totals 7700 MW in six states

A 500-kV line outage caused by malfunctioning protective relays led to widespread load shedding in six western states affecting nearly three million customers for periods as long as two hours.

The outage took place late in the afternoon on February 29 on the AC Pacific Northwest-Southwest Intertie and led to a total of nearly 7700 MW of load being automatically shed.

"This was not a blackout," said Robert Dintelman, assistant administrative manager of the 14-state Western Systems Coordinating Council (WSCC), referring to newspaper and television reports that called the out ages a blackout of the western U.S.

"We prevented a blackout by selected tripping of load," Dintelman added.

He explained that two sets of apparent equipment malfunctions led to the widespread load shedding program. The first was the failure on the AC Pacific Northwest Intertie, two 500-kV AC lines that pass from southern Oregon through Pacific Gas & Electric's system. The second was the failure of the WSCC system to automatically separate into northern and southern islands following the intertie outage as it was designed to do.

The 500 kV link opened late in the afternoon on February 28. The lines were fully loaded, carrying nearly 2800 MW from the Pacific Northwest to California utilities. A Pacific Gas & Electric spokesman said the failure had been traced to misoperation of protective relays as of early March.

WSCC's Dintelman said that, following the failure of the WSCC separation system to operate as designed, several transmission lines in states outside of California tripped out. The WSCC then separated into three islands: a capacity-deficient California-Southern Nevada region; a now ca-

Continued on page 2

FFTF to become working power reactor?

For about $150-million, plus some $42-million worth of materials and parts from the abandoned Clinch River Breeder Reactor, DOE's Fast Flux Test Facility, shown here, could be converted to a working power reactor capable of meeting all the electrical needs of the Hanford Engineering Development Laboratories. According to Westinghouse Electric Corp., operator of the DOE facility, a conceptual design report in support of project authorization was submitted at DOE's request last Fall in hopes of gaining authorization in the 1985 fiscal budget. The conversion would add steam generators to two of three existing secondary sodium cooling loops to drive a single turbine-generator. The power generated, 108 MWe (gross), would be fed to the Bonneville Power Administration grid. An article describing the achievements of the FFTF is scheduled to appear in May EL&P.

Behnke named Man of Year

BARRINGTON, IL—Commonwealth Edison Company Vice Chairman Wallace B. Behnke has been named Electric Industry Man of the Year for 1984.

Readers of *EL&P* voted Behnke the honor. Robert A. Lincicome, *EL&P* editor, said in announcing the award that Behnke was honored for his "personal leadership in the electric utility industry's battle to retain the nuclear power alternative and for his contribution to Commonwealth Edison's nuclear power construction program."

The award will be presented to Behnke at the All Engineers Dinner at the American Power Conference in Chicago April 25. The presentation, which will be made by Lincicome, carries with it a $1,000 contribution in Behnke's name to the university of his choice.

Behnke is the ninth man to receive the *EL&P* award. Last year's recipient was William Gould, chairman and chief executive officer of Southern California Edison Company.

A feature on Behnke begins on p11.

Foreign Power Briefs

• **China** has tentatively agreed to store large quantities of radioactive waste from European nuclear reactors in exchange for Western currency, reports *The Washington Post*. According to the *Post's* sources in China, the country will earn up to $6-billion over the next 16 years for storing radioactive wastes in the remote Gobi Desert. The newspaper said a letter of intent containing basics of the plan was signed in January between three West German firms active in the nuclear supply business and China Nuclear Energy Industry Corp., a state-run enterprise. The West German firms lined up dozens of contracts from nuclear facilities in western Europe. *The Post* said China agreed to receive 4,000 tons of spent nuclear fuel.

• **Pakistan's** national rural electrification program will be getting the assistance of 130 American Electric Power System (AEP) employees over the next five years. A joint venture made up of AEP Energy Services, Ebasco Overseas Corp., and International Training and Education Company received an $18-million contract to provide management and technical consulting services to Pakistan's Water and Power Development Authority, said AEP. The utility's employees will work in Pakistan for at least two years. They will be involved in management, finance, commercial operations and line-mechanic training. Other AEP employees will be in Pakistan for assignments ranging from one to 10 months.

• **The Canadian Electrical Association (CEA)** reports that national electricity consumption has been on a steady rise since June 1983. By November of last year, consumption was up 7.6 percent over the same period in 1982. CEA says that despite the upturn, Canada still has large energy surpluses. Seven new generating units went on-line in 1983 with a combined capacity of 2521 MW. According to CEA, half of the additions were nuclear plants. Nuclear power now comprises 8.4 percent of the total Canadian generating capacity.

• **A Swiss-designed magnetic coil**, shaped like a 44-ton doughnut, may hold the key for turning sea water into energy. Brown Boveri Corp., (BBC) said the 20 ft high magnetic coil will create a magnetic field 250,000 times stronger than the earth's magnetic field. BBC, manufacturer of the coil, said that if the technology succeeds, a large city can be supplied with electricity for months on just a few pounds of hydrogen. Scientists say the key to the technology is creating magnetic fields that can confine and heat hydrogen fuel to a temperature of 100 million degrees C.—about six times as hot as the sun's surface.

• **The Queensland Electricity Generating Board of Australia** said it has placed an order worth approximately $1 million with Westinghouse Electric Australasia Limited for a data acquisition system for the Swanbank B power station near Ipswich. The Westinghouse system will monitor the performance of Swanbank B's four 125,000-kW coal-burning units and supply the operators with the information they need to run the station and analyze the performance of the equipment.

• **Compagnia Elettrotecnica Italiana S.p.A.** (CEI), said it has received a $3-million contract from the Arab Sudanese Starch and Glucose Company to build a diesel power plant near Khartoum, Sudan. CEI is a wholly-owned company of the Dravo Corp. affiliate, Dravotec, S.p.A. of Milan. CEI said it will supply engineering, delivery, erection and technical assistance for the three, 1,500 MW diesel generators. The plant is scheduled to be completed in January 1985.

In This Issue

Editorial 4

Calendar 9

Wallace B. Behnke, vice chairman of Commonwealth Edison Company, has been selected 1983's Electric Industry Man of the Year by the readers of *EL&P*. 11

Load management received a lot of attention at the IEEE winter power meeting in Dallas. **T/D23** .....

Exotic energy sources don't look too promising in the near future in the opinion of many utility managers. **G** 31

New Products 49

New Literature 53

Personnel 60

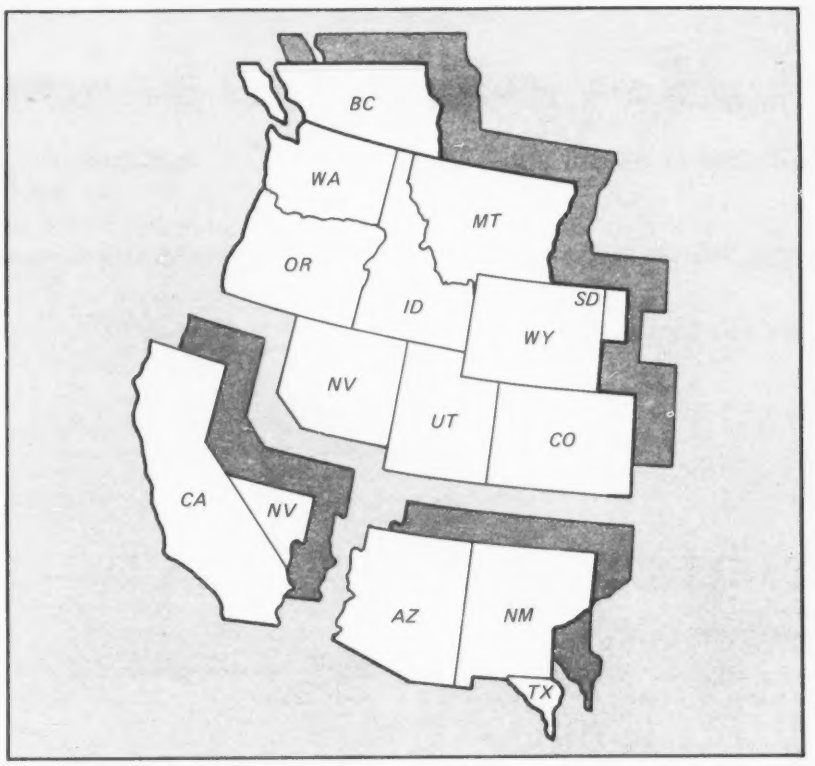
Readers' Service 61

Regulatory Review 66

Management Methods 68

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Load shedding . . . from page 1



Following the PG&E T-line outage, the WSCC separated into three islands and 7700 MW of load was shed in six states.

pacity-rich Arizona-New Mexico-El Paso island; and a third island containing the rest of the western states that was largely unaffected.

After the Arizona-New Mexico region separated, an over-frequency problem resulted from the generation surplus in that island causing several power plants to trip out.

The widespread load shedding took place automatically in response to the under-frequency resulting from the loss of generation. Relays operated to drop a total of 7716 MW of load in six states to balance generation with demand while generation was restored.

The largest amount of load was dropped by PG&E which cut off 2450 MW to about 1 million customers. At the time of the T-line outage PG&E demand was 10,500 MW. The intertie outage cost PG&E 1500 MW and the resulting separation from Arizona cut off 2000 MW more for PG&E and other California utilities.

PG&E reported that it brought hydro plants off reserve into operation and restored service to the "vast majority" of customers within 12 minutes. It took two hours to fully restore service.

The AC line that failed was reclosed and operating by 7 PM, slightly more than one hour after it went out of service. The line has been functioning normally since the outage but not at full load.

According to WSCC's Dintelman, other western utilities affected by load shedding included:

- Los Angeles Dept. of Water and Power—345,000 customers, 625 MW, service restored within one-half hour,
- Southern California Edison—750,000 customers, 2000 MW, back up within 18 minutes,
- San Diego Gas & Electric—149,000 customers, 250 MW, service back in two hours,
- Sacramento Municipal Utility District—60,000 customers, 120 MW, back in 10 to 20 minutes,
- Nevada Power—86,000 customers, 300 MW, back in one hour and 19 minutes,
- Arizona Public Service and Salt River Project in Phoenix—300,000 customers total, each dropped 600 MW for one hour,
- Sierra Pacific Power—50,000 customers, 200 MW for one hour,
- El Paso Electric—30,000 customers, 130 MW, back within one hour,
- Public Service of New Mexico—20,000 customers, 100 MW for 30 minutes.

Dintelman speculated that if the WSCC had separated as it was supposed to, there would have been less load shedding required.

Similar situation

He recalled that a line outage in December, 1982 caused by severe storm damage to transmission towers led to a similar situation. The line that went out was the same AC intertie, but the outage occurred south of San Francisco. There was even more load shed in California, Arizona, and Nevada in that occurrence, Dintelman said.

The official said a task force was being formed by WSCC to investigate the situation and recommend steps to correct any problems found.

PSI dismisses 80

PLAINFIELD, IN—Public Service Indiana (PSI) said it will dismiss 80 employees in the generation and transmission area.

The utility said the cuts will involve engineers, supervisors, training personnel, office workers and beginning bargaining unit employees at Public Service's generating stations.

PSI's Senior Vice President W.E. George said, "Unfortunately, it's necessary in the fossil power department to keep only those people with skills that are absolutely necessary to generate and transmit electricity. Therefore, we're making cuts in training and staff support services which are needed, but unfortunately we must do without because of our present cash-flow situation."

Since June 1982, the utility has reduced its non-nuclear work force by nearly 16 percent. In addition, said the utility, more than 1,100 PSI employees lost their jobs when construction was halted at the Marble Hill nuclear plant in January.

Revenues, earnings up

Electric utilities fare well in '83; weather plays big role

1984 YEAR-END UTILITY FINANCIAL RESULTS
Thousands

Utility	Revenues 1983		1983 EPS	
Arizona Public Service	$1,074,009	+1.0	$3.46	+4.8
Baltimore Gas & Electric	1,638,605	+4.8	4.95	+21.6
Black Hills Power & Light	62,601	+5.6	3.20	+18.1
Carolina Power & Light	1,647,183	+7.1	3.21	+1.3
Central Hudson	473,738	+6.3	3.94	+1.0
Central Illinois	733,042	+24.9	2.33	+28.7
Central Louisiana	304,282	+8.5	2.85	+15.4
Cleveland Electric Illuminating	1,210,316	+9.2	3.28	+9.0
Commonwealth Edison	4,570,072	+10.6	4.41	+16.4
Commonwealth Energy	619,655	+2.1	4.63	+89.0
Consolidated Edison	5,515,604	+8.8	4.16	+17.2
Dominion Resources	2,611,720	+10.6	3.28	+10.4
Eastern Utilities Associates	302,450	+4.9	2.80	+24.4
Empire District	116,079	+10.2	2.51	+19.0
Florida Progress	1,338,139	+10.3	2.64	+20.0
General Public Utilities	2,480,304	+3.1	.84	+37.7
Hawaiian Electric	622,578	-9.4	4.12	+.5
Indianapolis Power & Light	427,542	+7.5	4.17	+22.3
Iowa Public Service	388,090	+4.5	3.31	+47.1
Iowa Resources	457,916	+18.7	4.46	+21.9
Kansas Power & Light	859,572	+78.5	4.66	+29.4
Minnesota Power	374,068	+2.7	3.82	+8.8
Montana-Dakota	325,112	-8.4	3.90	-4.2
Montana Power	352,435	-3.0	4.22	+8.5
Northern States Power	1,695,800	+8.6	5.60	+16.9
Ohio Edison	1,515,852	+6.0	2.22	+4.2
Oklahoma Gas & Electric	972,281	+7.1	2.68	+4.3
Pennsylvania Power & Light	1,248,397	+2.4	3.06	-8.7
Potomac Electric	1,169,729	+6.8	2.66	+16.7
Public Service Indiana	873,900	+8.0	4.46	-2.0
Public Service New Hampshire	463,484	+9.5	3.49	+27.8
Public Service New Mexico	397,474	-6.8	3.53	+9.6
Puget Power	518,511	+10.9	1.93	-10.6
Savannah Electric	142,495	+4.6	2.66	+90.0
Southern Company	5,418,043	+10.0	2.70	+13.4
Southern Indiana Gas & Electric	276,727	+22.7	4.28	+25.1
Texas Utilities	849,543	+17.8	3.90	+1.3
Utah Power	863,288	+9.3	2.31	-5.7
The Washington Water Power Co.	338,812	-.02	3.02	-4.7
Wisconsin Power & Light	555,502	+8.4	3.97	+13.1
TOTALS	**45,804,950**	**+8.4**	**137.62**	**+13.9**

Don Minner
Assistant Editor

BARRINGTON, IL—It was a banner year for most of the nation's investor-owned electric utilities.

An *EL&P* survey of 40 electric utility year-end financial statements shows that 1983 operating revenues were up 8.4 percent, while earnings per share rocketed 13.9 percent over 1982's figures.

In comparison, operating revenues of *EL&P's* Annual Top 100 electric utilities were up 9.5% in 1982, 20.3% in 1981 and 15.9% in 1980. Earnings per share rose 6.4% in 1982, 11.9% in 1981 and .4% in 1980.

Last summer's unusually hot weather and an early, harsh winter were the principal reasons for the revenue increase. A large majority of the randomly selected utilities reported that weather was the major factor in raising operating revenues.

Economy growing

A continued nationwide economic recovery also contributed heavily to the strong performance in 1983 by the country's electric utilities.

The Commerce Department reported that the economy grew at a 4.9 percent annual rate in the fourth quarter, compared to 7.6 percent in the third quarter. The nation's output before adjustment for inflation, in the fourth quarter, was $3.437 trillion, up from $3.362 trillion in the third quarter of 1983.

Consolidated Edison said operating revenues for 1983 were up 8.8 percent over 1982, while earnings per share increased 17.2 percent. Arthur Hauspurg, chairman of the board, said, "The increase in earnings was due in large part to the extremely hot summer. The summer of '83 was the second hottest since ConEd became a summer peaking company some 25 years ago."

Weather also contributed to the brighter financial picture for Wisconsin Power & Light, Montana Power, Iowa Resources and Northern States Power.

Many utilities said they are continuing the cost control measures instituted during the recession. Central Louisiana Electric Chairman and President James Henderson said that he is optimistic about the future. "However," he added, "we will maintain a hard line on expenses and take advantage of every opportunity to increase efficiency."

Effective cost controls

Minnesota Power Chairman and CEO Jack Rowe said his company's modest advances in 1983 were accomplished "through increased electric revenues and non-utility investment income, lower interest charges and effective cost controls." Rowe said Minnesota Power has not sought a rate increase in three years and has no plans to do so in 1984.

Baltimore Gas & Electric also said it is keeping its cost control measures in place, although the utility said economic conditions are improving in its service area.

Business and industry are slowly picking up activity in the battered Northeast. Pennsylvania Power & Light said industrial sales were up 4.1 percent in 1983 and commercial sales rose 2.9 percent. Central Hudson reported that industrial sales jumped 7 percent, due in large part to renewed activity with the region's cement companies.

Ohio Edison said it saw a "steady improvement in the local economy, particularly in the automotive and steel groups." The utility said that sales of electricity to other utilities resulted in $76.2 million of Edison's total revenue in 1983.

While most utilities fared well during the year, others with nuclear plants under construction saw earnings drop. Public Service of Indiana, which abandoned its Marble Hill plant in January, saw its earnings per share drop 2.0 percent to $4.46 in 1983. PSI said in January that it was going to cut its dividend by 65 percent. The utility said the "substantial decline in earnings for 1983" was due to the discontinuation of allowance for funds used during construction (AFUDC) for Marble Hill.

EL&P TOP 100 SURVEY (1978–1982)

	Operating revenues		Earnings per share	
1982	123.4 billion	+9.5	3.00	+6.4
1981	112.7 billion	+20.3	2.82	+11.9
1980	93.6 billion	+15.9	2.52	+.4
1979	80.8 billion	+13.5	2.51	+.4
1978	71.2 billion		2.50	

Arizona Public Service, the lead utility in construction of the three unit Palo Verde nuclear plant, said 85 percent of its earnings figure in 1983 was due to AFUDC, compared to 72 percent last year.

PP&L earnings drop

The owner of the nearly complete Susquehanna-2 nuclear unit, Pennsylvania Power & Light, said its 8.7 percent dip in earnings per share was due to a number of factors. PP&L Executive Vice President Robert Fortune said, "Higher costs, a regulatory decision that does not allow us to earn a return on part of our investment in generating facilities, the lingering effects of the recession during early 1983 and an increase in the number of common shares outstanding were factors in the decline."

Montana-Dakota Utilities said its earnings per share drop in 1983 was due to the sale of more common shares of stock.

The Southern Company, Commonwealth Energy, Hawaiian Electric Industries and Carolina Power & Light all reported healthy increases.

Dominion Resources, holding company for Virginia Electric and Power Company, said 1983 brought record earnings to the company. Contributing to the earnings rise was the sale of a portion of the North Anna nuclear Units 1 and 2 to the Old Dominion Electric Cooperative.

Outside the utility industry, profits were much higher in the fourth quarter than in 1982. A *Wall Street Journal* survey of 529 major corporations in February found that after-tax earnings rose 64 percent in the fourth quarter. A *Journal* survey of 115 Canadian companies found fourth quarter earnings skyrocket 118 percent from a year earlier.

JCP&L agrees to PP&L power buy

PARSIPPANY, NJ—General Public Utilities announced that a long-term power purchase agreement has been reached with Pennsylvania Power & Light for its New Jersey susbsidiary.

Beginning in June, Jersey Central Power & Light Company will buy 945 MW of power through 1995, with the amount declining uniformly each year through 1999. PP&L will be selling 12.6 percent of its electrical output. The power will be priced at cost of service.

GPU said the fuel mix of the purchase will be approximately 25 percent from nuclear, 65 percent from coal and the remainder from oil and other sources.

Herman Dieckamp, GPU president, said the purchase will supply approximately 30 percent of Jersey Central's energy requirements. "Over the long term," said Dieckamp, "the agreement is expected to produce substantial cost savings for Jersey Central customers because over the life of the contract, the cost of the purchase is expected to be well below that of alternative sources, including new capacity."

GPU strategy

Dieckamp said the agreement reflects GPU's strategy of buying power, so that construction of new generating capacity can be deferred.